

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

[Amdt. 191-6, 53 FR 24949, July 1, 1988; 53 FR 29800, Aug. 8, 1988, as amended by Amdt. 191-7, 54 FR 32344, Aug. 7, 1989; Amdt. 191-8, 54 FR 40878, Oct. 4, 1989; Amdt. 191-10, 61 FR 18516, Apr. 26, 1996; Amdt. 191-23, 80 FR 12777, Mar. 11, 2015]

§ 191.29 National Pipeline Mapping System.

(a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

(1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

(2) The name of and address for the operator.

(3) The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.

(b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes

have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

[Amdt. 191-23, 80 FR 12777, Mar. 11, 2015]

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

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APPENDIX A TO PART 192 [RESERVED]

APPENDIX B TO PART 192—QUALIFICATION OF PIPE

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APPENDIX D TO PART 192—CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

APPENDIX E TO PART 192—GUIDANCE ON DETERMINING HIGH CONSEQUENCE AREAS AND ON CARRYING OUT REQUIREMENTS IN THE INTEGRITY MANAGEMENT RULE

AUTHORITY: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, 60141; and 49 CFR 1.97.

SOURCE: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.

EDITORIAL NOTE: Nomenclature changes to part 192 appear at 71 FR 33406, June 9, 2006.

Subpart A—General

§ 192.1 What is the scope of this part?

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may peti-

tion the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in § 192.8); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612; or

(5) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-67, 56 FR 63771, Dec. 5, 1991; Amdt. 192-78, 61 FR 28782, June 6, 1996; Amdt. 192-81, 62 FR 61695, Nov. 19, 1997; Amdt. 192-92, 68 FR 46112, Aug. 5, 2003; 70 FR 11139, Mar. 8, 2005; Amdt. 192-102, 71 FR 13301, Mar. 15, 2006; Amdt. 192-103, 72 FR 4656, Feb. 1, 2007]

§ 192.3 Definitions.

As used in this part:

Abandoned means permanently removed from service.

Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

Customer meter means the meter that measures the transfer of gas from an operator to a consumer.

Distribution line means a pipeline other than a gathering or transmission line.

Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line section means a continuous run of transmission line between adjacent

compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed specification means a specification listed in section I of appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Municipality means a city, county, or any other political subdivision of a State.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator means a person who engages in the transportation of gas.

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders.

Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Service regulator means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Supervisory Control and Data Acquisition (SCADA) system means a computer-

based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

NOTE: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

Underground natural gas storage facility means a facility that stores natural gas in an underground facility incident to natural gas transportation, including—

- (1) A depleted hydrocarbon reservoir; or
- (2) An aquifer reservoir; or
- (3) A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.

Welder means a person who performs manual or semi-automatic welding.

Welding operator means a person who operates machine or automatic welding equipment.

[Amdt. 192-13, 38 FR 9084, Apr. 10, 1973]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.3, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.fdsys.gov.

§ 192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

§ 192.7

49 CFR Ch. I (10-1-18 Edition)

(1) A "class location unit" is an on-shore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

[Amdt. 192-78, 61 FR 28783, June 6, 1996; 61 FR 35139, July 5, 1996, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval

of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the FEDERAL REGISTER.

(1) *Availability of standards incorporated by reference.* All of the materials incorporated by reference are available for inspection from several sources, including the following:

(i) The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. For more information contact 202-366-4046 or go to the PHMSA Web site at: <http://www.phmsa.dot.gov/pipeline/regs>.

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.

(iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

(2) [Reserved]

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000, <http://api.org/>.

(1) API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe," 7th edition, September 2009, (API RP 5L1), IBR approved for § 192.65(a).

(2) API Recommended Practice 5LT, "Recommended Practice for Truck Transportation of Line Pipe," First edition, March 2012, (API RP 5LT), IBR approved for § 192.65(c).

(3) API Recommended Practice 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels," 3rd edition, September 2009, (API RP 5LW), IBR approved for § 192.65(b).

(4) API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," 1st edition, April 2000, (API RP 80), IBR approved for § 192.8(a).

(5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162), IBR approved for § 192.616(a), (b), and (c).

(6) API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165), IBR approved for § 192.631(c).

(7) API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (API Spec 5L), IBR approved for §§ 192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.

(8) ANSI/API Specification 6D, "Specification for Pipeline Valves," 23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata 2 (November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D), IBR approved for § 192.145(a).

(9) API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104), IBR approved for §§ 192.225(a); 192.227(a); 192.229(c); 192.241(c); and Item II, Appendix B.

(10) API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170), IBR approved for § 192.12.

(11) API Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," First edition, September 2015, (API RP 1171), IBR approved for § 192.12.

(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), <http://www.asme.org/>.

(1) ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006, (ASME/ANSI B16.1), IBR approved for § 192.147(c).

(2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings," October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a) and 192.279.

(3) ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c) and 192.933(a).

(4) ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007, (ASME/ANSI B31.8), IBR approved for §§ 192.112(b) and 192.619(a).

(5) ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004, (ASME/ANSI B31.8S-2004), IBR approved for §§ 192.903 note to *Potential impact radius*; 192.907 introductory text, (b); 192.911 introductory text, (i), (k), (l), (m); 192.913(a), (b), (c); 192.917 (a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935 (a), (b); 192.937(c); 192.939(a); and 192.945(a).

(6) ASME Boiler & Pressure Vessel Code, Section I, "Rules for Construction of Power Boilers 2007," 2007 edition, July 1, 2007, (ASME BPVC, Section I), IBR approved for § 192.153(b).

(7) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §§ 192.153(a), (b), (d); and 192.165(b).

(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2), IBR approved for §§ 192.153(b), (d); and 192.165(b).

(9) ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, ASME BPVC, Section IX, IBR approved for §§ 192.225(a); 192.227(a); and Item II, Appendix B to Part 192.

(d) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: <http://www.astm.org/>.

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(1) ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M), IBR approved for §192.113; and Item II, Appendix B to Part 192.

(2) ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010, (ASTM A106/A106M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(3) ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(4) ASTM A372/A372M-10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010, (ASTM A372/A372M), IBR approved for §192.177(b).

(5) ASTM A381-96 (reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005, (ASTM A381), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(6) ASTM A578/A578M-96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications," (ASTM A578/A578M), IBR approved for §192.112(c).

(7) ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010, (ASTM A671/A671M), IBR approved for §192.113; and Item I, Appendix B to Part 192.

(8) ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009, (ASTM A672/A672M), IBR approved for §192.113 and Item I, Appendix B to Part 192.

(9) ASTM A691/A691M-09, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures," approved October 1, 2009, (ASTM A691/A691M), IBR approved for

§192.113 and Item I, Appendix B to Part 192.

(10) ASTM D638-03, "Standard Test Method for Tensile Properties of Plastics," 2003, (ASTM D638), IBR approved for §192.283(a) and (b).

(11) ASTM D2513-87, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (ASTM D2513-87), IBR approved for §192.63(a).

(12) ASTM D2513-99, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings," (ASTM D 2513-99), IBR approved for §§192.191(b); 192.281(b); 192.283(a) and Item 1, Appendix B to Part 192.

(13) ASTM D2513-09a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved December 1, 2009, (ASTM D2513-09a), IBR approved for §§192.123(e); 192.191(b); 192.283(a); and Item 1, Appendix B to Part 192.

(14) ASTM D2517-00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517), IBR approved for §§192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.

(15) ASTM F1055-1998, "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controller Polyethylene Pipe and Tubing," (ASTM F1055), IBR approved for §192.283(a).

(e) Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: www.gastechnology.org.

(1) GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology," (GRI 02/0057), IBR approved for §192.927(c).

(2) [Reserved]

(f) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: <http://www.mss-hq.org/>.

(1) MSS SP-44-2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44), IBR approved for §192.147(a).

(2) [Reserved]

(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084;

phone: 281-228-6223 or 800-797-6223, Web site: <http://www.nace.org/Publications/>.

(1) ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010, (NACE SP0502), IBR approved for §§ 192.923(b); 192.925(b); 192.931(d); 192.935(b) and 192.939(a).

(2) [Reserved]

(h) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275. Web site: <http://www.nfpa.org/>.

(1) NFPA-30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30), IBR approved for § 192.735(b).

(2) NFPA-58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)," (NFPA-58), IBR approved for § 192.11(a), (b), and (c).

(3) NFPA-59 (2004), "Utility LP-Gas Plant Code," (NFPA-59), IBR approved for § 192.11(a), (b); and (c).

(4) NFPA-70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA-70), IBR approved for §§ 192.163(e); and 192.189(c).

(1) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: <http://www.ttoolbox.com/>. (Contract number PR-3-805.)

(1) AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§ 192.485(c); 192.933(a) and (d).

(2) [Reserved]

(j) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, <http://www.plasticpipe.org/>.

(1) PPI TR-3/2008 HDB/HDS/PDB/SDB/MRS Policies (2008), "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Pressure Design Basis (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe," May 2008, IBR approved for § 192.121.

(2) [Reserved]

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.7, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.fdsys.gov.

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) An operator must use API RP 80 (incorporated by reference, see § 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthestmost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthestmost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation."

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR § 190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthestmost

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downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(b) For purposes of § 192.9, “regulated onshore gathering line” means:

(1) Each onshore gathering line (or segment of onshore gathering line)

with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	<p>—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.</p> <p>—Non-metallic and the MAOP is more than 125 psig (862 kPa).</p>	Class 2, 3, or 4 location (see § 192.5)	None.
B	<p>—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.</p> <p>—Non-metallic and the MAOP is 125 psig (862 kPa) or less.</p>	<p>Area 1. Class 3 or 4 location</p> <p>Area 2. An area within a Class 2 location the operator determines by using any of the following three methods:</p> <p>(a) A Class 2 location</p> <p>(b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings.</p> <p>(c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.</p>	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

[Amdt. 192-102, 71 FR 13302, Mar. 15, 2006]

§ 192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under § 192.614;

(4) Establish a public education program under § 192.616;

(5) Establish the MAOP of the line under § 192.619; and

(6) Install and maintain line markers according to the requirements for transmission lines in § 192.707.

(7) Conduct leakage surveys in accordance with § 192.706 using leak detection equipment and promptly repair

hazardous leaks that are discovered in accordance with § 192.703(c).

(e) *Compliance deadlines.* An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.

(1) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in § 192.13 applies.

(2) If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
Control corrosion according to Subpart I requirements for transmission lines.	April 15, 2009.
Carry out a damage prevention program under § 192.614.	October 15, 2007.
Establish MAOP under § 192.619.	October 15, 2007.
Install and maintain line markers under § 192.707.	April 15, 2008.
Establish a public education program under § 192.616.	April 15, 2008.
Other provisions of this part as required by paragraph (c) of this section for Type A lines.	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.

[Amdt. 192-102, 71 FR 13301, Mar. 15, 2006, as amended by Amdt. 192-120, 80 FR 12777, Mar. 11, 2015]

§ 192.10 Outer continental shelf pipelines.

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act; 43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing

operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Amdt. 192-81, 62 FR 61695, Nov. 19, 1997, as amended at 70 FR 11139, Mar. 8, 2005]

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA 58 and NFPA 59 (incorporated by reference, see § 192.7).

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and NFPA 58 and NFPA 59 (incorporated by reference, see § 192.7), NFPA 58 and NFPA 59 prevail.

[Amdt. 192-78, 61 FR 28783, June 6, 1996, as amended by Amdt. 192-119, 80 FR 180, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.12 Underground natural gas storage facilities.

Underground natural gas storage facilities must meet the following requirements:

(a) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for gas storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1170 (incorporated by reference, see § 192.7).

(b) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for storage

including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1170, sections 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.

(c) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1171 (incorporated by reference, see § 192.7).

(d) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage, including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1171, sections 8, 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.

(e) Operators of underground gas storage facilities must establish and follow written procedures for operations, maintenance, and emergencies implementing the requirements of API RP 1170 and API RP 1171, as required under this section, including the effective dates as applicable, and incorporate such procedures into their written procedures for operations, maintenance, and emergencies established pursuant to § 192.605.

(f) With respect to the incorporation by reference of API RP 1170 and API RP 1171 in this section, the non-mandatory provisions (i.e., provisions containing the word "should" or other non-mandatory language) are adopted as mandatory provisions under the authority of the pipeline safety laws except when the operator includes or references written technical justifications in its program or procedural manual, described in paragraph (a)(5) of this

section, as to why compliance with a provision of the recommended practice is not practicable and not necessary for safety with respect to specified underground storage facilities or equipment. The justifications for any deviation from any provision of API RP 1170 and API RP 1171 must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility. An operator must discontinue use of any variance where PHMSA determines and provides notice that the variance adversely impacts design, construction, operations, maintenance, integrity, emergency preparedness and response, or overall safety.

[Amdt. 192-122, 81 FR 91873, Dec. 19, 2016]

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15 2007.
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15, 2007.
All other pipelines	November 12, 1970.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-30, 42 FR 60148, Nov. 25, 1977; Amdt. 192-102, 71 FR 13303, Mar. 15, 2006]

§ 192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart J of this part to substantiate the maximum allowable operating pressure permitted by subpart L of this part.

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

(c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days

before the conversion occurs as required by § 191.22 of this chapter.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

§ 192.15 Rules of regulatory construction.

(a) As used in this part:

Includes means including but not limited to.

May means "is permitted to" or "is authorized to".

May not means "is not permitted to" or "is not authorized to".

Shall is used in the mandatory and imperative sense.

(b) In this part:

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

§ 192.16 Customer notification.

(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to § 192.465 if the customer's buried piping is metallic, survey for leaks according to § 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

(b) Each operator shall notify each customer once in writing of the following information:

(1) The operator does not maintain the customer's buried piping.

(2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

(3) Buried gas piping should be—

(1) Periodically inspected for leaks;

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(ii) Periodically inspected for corrosion if the piping is metallic; and

(iii) Repaired if any unsafe condition is discovered.

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.

(d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(1) A copy of the notice currently in use; and

(2) Evidence that notices have been sent to customers within the previous 3 years.

[Amdt. 192-74, 60 FR 41828, Aug. 14, 1995, as amended by Amdt. 192-74A, 60 FR 63451, Dec. 11, 1995; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998]

Subpart B—Materials

§ 192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

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§ 192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of appendix B to this part;

(2) It meets the requirements of:

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L (incorporated by reference, *see* § 192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 191-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-12, 38 FR 4761, Feb. 22, 1973; Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; 59 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-119, 80 FR 180, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015]

§ 192.57 [Reserved]

§ 192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if:

(1) It is manufactured in accordance with a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

(d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-19, 40 FR 10472, Mar. 6, 1975; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.61 [Reserved]

§ 192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D2513-87 (incorporated by reference, *see* § 192.7);

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-31, 43 FR 883, Apr. 3, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; Amdt. 192-61A, 54 FR 32642, Aug. 9, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-76, 61 FR 26122, May 24, 1996; 61 FR 36826, July 15, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.65 Transportation of pipe.

(a) *Railroad.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, *see* § 192.7).

(b) *Ship or barge.* In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not

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use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, *see* § 192.7).

(c) *Truck*. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, *see* § 192.7).

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 180, Jan. 5, 2015; Amdt. 192-120, 80 FR 12777, Mar. 11, 2015]

Subpart C—Pipe Design

§ 192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

$$P = (2 S/tD) \times F \times E \times T$$

P = Design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) determined in accordance with § 192.107.

D = Nominal outside diameter of the pipe in inches (millimeters).

t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.

F = Design factor determined in accordance with § 192.111.

E = Longitudinal joint factor determined in accordance with § 192.113.

T = Temperature derating factor determined in accordance with § 192.115.

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(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900 °F (482 °C) at any time or is held above 600 °F (316 °C) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-47, 49 FR 7569, Mar. 1, 1984; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.107 Yield strength (*S*) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 p.s.i. (165 MPa).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-83, 63 FR 7723, Feb. 17, 1998; Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.109 Nominal wall thickness (*t*) for steel pipe.

(a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less

than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.111 Design factor (F) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Class location	Design factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

(b) A design factor of 0.60 or less must be used in the design formula in § 192.105 for steel pipe in Class 1 locations that:

- (1) Crosses the right-of-way of an unimproved public road, without a casing;
- (2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for—

- (1) Steel pipe in a compressor station, regulating station, or measuring station; and
- (2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under § 192.620, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this design issue:	The pipeline segment must meet these additional requirements:
(a) General standards for the steel pipe.	<ul style="list-style-type: none"> (1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment. (2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bossyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula. (3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses. (4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see § 192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.

To address this design issue:	The pipeline segment must meet these additional requirements:
(b) Fracture control	<p>(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:</p> <ul style="list-style-type: none"> (i) API Spec 5L (incorporated by reference, see § 192.7); or (ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see § 192.7); and (iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L, product specification level 2 or ASME B31.8 (incorporated by reference, see § 192.7). <p>(2) Fracture control must:</p> <ul style="list-style-type: none"> (i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline; (ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters; (iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and (iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see § 192.7) and ensures ductile fracture and arrest with the following exceptions: <ul style="list-style-type: none"> (A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and (B) The results of the drop weight test prescribed in SR6 must indicate 60 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest. <p>(3) If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.</p>
(c) Plate/coil quality control	<p>(1) There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality.</p> <p>(2) A mill inspection program or internal quality management program must include (i) and either (ii) or (iii):</p> <ul style="list-style-type: none"> (i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see § 192.7) or equivalent method, and either (ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or (iii) A quality assurance monitoring program implemented by the operator that includes audits of: (a) all steelmaking and casting facilities, (b) quality control plans and manufacturing procedure specifications, (c) equipment maintenance and records of conformance, (d) applicable casting superheat and speeds, and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.
(d) Seam quality control	<p>(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see § 192.7) for appropriate grades.</p> <p>(2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following:</p> <ul style="list-style-type: none"> (i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and (ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal). <p>(3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.</p>
(e) Mill hydrostatic test	<p>(1) All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds.</p> <p>(2) Pipe in operation prior to December 22, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds.</p> <p>(3) Pipe in operation on or after December 22, 2008, but before October 1, 2015, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by "ANSI/API Spec 5L" (incorporated by reference, see § 192.7).</p>
(f) Coating	<p>(1) The pipe must be protected against external corrosion by a non-shielding coating.</p>

To address this design issue:	The pipeline segment must meet these additional requirements:
(g) Fittings and flanges	<p>(2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation.</p> <p>(3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.</p> <p>(1) There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions.</p> <p>(2) If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure.</p> <p>(3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.</p>
(h) Compressor stations	<p>(1) A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in paragraph (h)(2) of this section unless a long-term coating integrity monitoring program is implemented in accordance with paragraph (h)(3) of this section.</p> <p>(2) If research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.</p> <p>(3) Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) if the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to each PHMSA pipeline safety regional office in which the pipeline is located for review before the pipeline segments may be operated at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.</p>

[73 FR 62175, Oct. 17, 2008, as amended by Amdt. 192-111, 74 FR 62505, Nov. 30, 2009; Amdt. 192-119, 80 FR 180, Jan. 5, 2015; Amdt. 192-120, 80 FR 12777, Mar. 11, 2015]

§ 192.113 Longitudinal joint factor (E) for steel pipe.

The longitudinal joint factor to be determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded60
ASTM A 106	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded60
Other	Pipe over 4 inches (102 millimeters)80
Other	Pipe 4 inches (102 millimeters) or less60

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If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

[Amdt. 192-37, 46 FR 10159, Feb. 2, 1981, as amended by Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 180, Jan. 5, 2015]

§ 192.115 Temperature derating factor (T) for steel pipe.

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
250 °F (121 °C) or less	1.000

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Gas temperature in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
300 °F (149 °C)	0.987
350 °F (177 °C)	0.933
400 °F (204 °C)	0.900
450 °F (232 °C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§§ 192.117-192.119 [Reserved]

§ 192.121 Design of plastic pipe.

Subject to the limitations of § 192.123, the design pressure for plastic pipe is determined by either of the following formulas:

$$P = 2S \frac{t}{(D-t)} (DF)$$

$$P = \frac{2S}{(SDR-1)} (DF)$$

Where:

P = Design pressure, gauge, psig (kPa).
 S = For thermoplastic pipe, the HDB is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2008, *HDB/PDB/SDB/MRS Policies* (incorporated by reference, see § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa). [Note: Arithmetic interpolation is not allowed for PA-11 pipe.]

t = Specified wall thickness, inches (mm).
 D = Specified outside diameter, inches (mm).
 SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.
 DF = 0.32 or
 = 0.40 for PA-11 pipe produced after January 23, 2009 with a nominal pipe size (IPS or CTS)

4-inch or less, and a SDR of 11 or greater (i.e., thicker pipe wall).

[Amdt. 192-111, 74 FR 62505, Nov. 30, 2009, as amended by Amdt. 192-114, 75 FR 48603, Aug. 11, 2010]

§ 192.123 Design limitations for plastic pipe.

(a) Except as provided in paragraph (e) and paragraph (f) of this section, the design pressure may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:

- (1) Distribution systems; or
- (2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

- (1) Below -20 °F (-20 °C), or -40 °F (-40 °C) if all pipe and pipeline components whose operating temperature will be below -29 °C (-20 °F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the HDB used in the design formula under §192.121 is determined.

(ii) For reinforced thermosetting plastic pipe, 150 °F (66 °C).

(c) The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches (millimeters).	Minimum wall thickness inches (millimeters).
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(e) The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 125 psig (862 kPa);

(2) The material is a polyethylene (PE) pipe with the designation code as specified within ASTM D2513-09a (incorporated by reference, see §192.7);

(3) The pipe size is nominal pipe size (IPS) 12 or less; and

(4) The design pressure is determined in accordance with the design equation defined in §192.121.

(f) The design pressure for polyamide-11 (PA-11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 psig (689 kPa) provided that:

(1) The design pressure does not exceed 200 psig (1379 kPa);

(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and

(3) The pipe has a standard dimension ratio of SDR-11 or greater (i.e., thicker pipe wall).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978; Amdt. 192-78, 61 FR 28783, June 6, 1996; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; 69 FR 32894, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-103, 71 FR 33407, June 9, 2006; 73 FR 79005, Dec. 24, 2008; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard size inch (millimeter)	Nominal O.D. inch (millimeter)	Wall thickness inch (millimeter)	
		Nominal	Tolerance
½ (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
¾ (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
¾ (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (25)	1.125 (29)	.050 (1.27)	.004 (.102)
1¼ (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1½ (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft³ (6.9/m³) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (15.6 °C and one atmosphere) of gas.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 192-85, 63 FR 37502, July 13, 1998]

Subpart D—Design of Pipeline Components

§ 192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§ 192.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure

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testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in subpart I of this part.

[Amdt. 48, 49 FR 19824, May 10, 1984, as amended at 73 FR 20059, Apr. 23, 2007]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in §192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B of this part:

- (1) Pressure testing;
- (2) Materials; and
- (3) Pressure and temperature ratings.

[Amdt. 192-45, 48 FR 30639, July 5, 1983, as amended by Amdt. 192-94, 69 FR 32894, June 14, 2004]

§ 192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, see §192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-84, 69 FR 32894, June 14, 2004; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B 16.5 and MSS SP-44 (incorporated by reference, see §192.7), or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and

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chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see §192.7) and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to: (1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore transmission lines, except transmission lines 10 $\frac{3}{4}$ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless—

(i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or

(ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; and

(8) Other piping that, under §190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-97, 69 FR 36029, June 28, 2004]

§ 192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at

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least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1¼-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37502, July 13, 1998]

§ 192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see § 192.7).

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1 of the ASME BPVC (Section VIII, Division 1 or Section VIII, Division 2) (incorporated by reference, see § 192.7), except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

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(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.

(e) A component having a design pressure established in accordance with paragraph (a) or paragraph (b) of this section and subject to the strength testing requirements of § 192.505(b) must be tested to at least 1.5 times the MAOP.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192-68, 58 FR 45268, Aug. 27, 1993; Amdt. 192-85, 63 FR 37502, July 13, 1998; Amdt. 192-119, 80 FR 181, Jan. 5, 2015; Amdt. 192-120, 80 FR 12778, Mar. 11, 2015; Amdt. 192-119, 80 FR 46847, Aug. 6, 2015]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal

expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

- (1) Prevent undue strain on connected equipment;
- (2) Resist longitudinal forces caused by a bend or offset in the pipe; and
- (3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

- (1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
- (2) Provision must be made for the service conditions involved.
- (3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

- (1) A structural support may not be welded directly to the pipe.
- (2) The support must be provided by a member that completely encircles the pipe.
- (3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being con-

nected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.163 Compressor stations: Design and construction.

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either—

- (1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or
- (2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70, so far as that code is applicable.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37502, 37503, July 13, 1998; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.165 Compressor stations: Liquid removal.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

(1) Have a manually operable means of removing these liquids.

(2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

(3) Be manufactured in accordance with section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, *see* § 192.7) and the additional requirements of § 192.153(e) except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015; Amdt. 192-120, 80 FR 12778, Mar. 11, 2015]

§ 192.167 Compressor stations: Emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities

in the vicinity of gas headers and in the compressor building, except that:

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least two locations, each of which is:

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet (153 meters) from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station:

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building:

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility which conforms to Class 1, Group D, of the National Electrical Code is not a source of ignition.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.169 Compressor stations: Pressure limiting devices.

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor stations: Additional safety equipment.

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor stations: Ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§ 192.175 Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder must be designed so as to pre-

vent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C = (3D \cdot P \cdot F) / 1000 \text{ in inches; } (C = (3D \cdot P \cdot F) / 6,895 \text{ in millimeters})$$

In which:

C = Minimum clearance between pipe containers or bottles in inches (millimeters).

D = Outside diameter of pipe containers or bottles in inches (millimeters).

P = Maximum allowable operating pressure, psi (kPa) gauge.

F = Design factor as set forth in § 192.111 of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

§ 192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

(2) Designed using the design factors set forth in § 192.111; and

(3) Buried with a minimum cover in accordance with § 192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M (incorporated by reference, see § 192.7).

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small

diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by subpart J of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles (4 kilometers) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an

overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping

may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

- (a) Street intersections or points where traffic is heavy or dense;
- (b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
- (c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

- (a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

- (b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.189 Vaults: Drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference, *see* § 192.7).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-76, 61 FR 26122, May 24, 1996; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517, (incorporated by reference, *see* § 192.7).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a for polyethylene plastic materials.

[Amdt. 192-114, 75 FR 48603, Aug. 11, 2010, as amended by Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§ 192.195 Protection against accidental overpressuring.

(a) *General requirements.* Except as provided in § 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation

of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i. (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i. (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i. (414 kPa) gage or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed

the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i. (862 kPa) gage. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or

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near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-9, 37 FR 20827, Oct. 4, 1972; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.203 Instrument, control, and sampling pipe and components.

(a) *Applicability.* This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) *Materials and design.* All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400 °F (204 °C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner

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suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

Subpart E—Welding of Steel in Pipelines

§ 192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.225 Welding procedures.

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* § 192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* § 192.7) to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the applicable welding standard(s).

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

[Amdt. 192-52, 61 FR 20297, June 4, 1986; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015; Amdt. 192-120, 80 FR 12778, Mar. 11, 2015; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

§ 192.227 Qualification of welders and welding operators.

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, *see* §192.7), or section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, *see* §192.7). However, a welder or welding operator qualified under an earlier edition than the listed in §192.7 of this part may weld but may not re-qualify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

[Amdt. 192-120, 80 FR 12778, Mar. 11, 2015, as amended by Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

§ 192.229 Limitations on welders and welding operators.

(a) No welder or welding operator whose qualification is based on non-destructive testing may weld compressor station pipe and components.

(b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process.

(c) A welder or welding operator qualified under §192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, *see* §192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing

welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7½ months. A welder or welding operator qualified under an earlier edition of a standard listed in §192.7 of this part may weld, but may not re-qualify under that earlier edition; and.

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or re-qualifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder or welding operator qualified under §192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under §192.227(b); or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder or welding operator has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[Amdt. 192-120, 80 FR 12778, Mar. 11, 2015]

§ 192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12½° and

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must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.241 Inspection and test of welds.

(a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

(1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Std 1104 (incorporated by reference, *see* § 192.7). Appendix A of API

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Std 1104 may not be used to accept cracks.

[36 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32894, June 14, 2004; Amdt. 192-119, 80 FR 181, Jan. 5, 2015; Amdt. 192-120, 80 FR 12778, Mar. 11, 2015]

§ 192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).

(d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).

(f) When nondestructive testing is required under § 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-50, 50 FR 37192, Sept. 12, 1985; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-120, 80 FR 12779, Mar. 11, 2015]

§ 192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192-46, 48 FR 48674, Oct. 20, 1983]

Subpart F—Joining of Materials Other Than by Welding

§ 192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain

the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5628, Feb. 6, 1989, as amended at 58 FR 14521, Mar. 18, 1993]

§ 192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

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(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2513-99, (incorporated by reference, *see* §192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, *see* §192.7).

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.283 Plastic pipe: Qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513-99 for plastic materials other than polyethylene or ASTM D2513-09a (incorporated by reference, *see* §192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, *see* §192.7); or

(iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, *see* §192.7).

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, *see* §192.7), except that the test may be conducted at ambient temperature and humidity if the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the

procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning). (incorporated by reference, *see* § 192.7).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 4 inches (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 192-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.285 Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; Amdt. 192-120, 80 FR 12779, Mar. 11, 2015]

§ 192.287 Plastic pipe: Inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that

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person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192-34, 44 FR 42974, July 23, 1979]

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§ 192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

EFFECTIVE DATE NOTE: At 80 FR 12779, Mar. 11, 2015, § 192.305 was revised, effective Oct. 1, 2015. At 80 FR 58633, Sept. 30, 2015, this amendment was delayed indefinitely. For the convenience of the user, the revised text is set forth as follows:

§ 192.305 Inspection: General.

Each transmission line and main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

§ 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§ 192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or re-

moved. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

- (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or
- (2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than ¼ inch (6.4 millimeters) in pipe 12¾ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12¾ inches (324 millimeters) in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999]

§ 192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

[Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.313 Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

[Amdt. 192-26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192-29, 42 FR 42866, Aug. 25, 1977; Amdt. 192-29, 42 FR 60148, Nov. 25, 1977; Amdt. 192-49, 50 FR 13225, Apr. 3, 1985; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than $1\frac{1}{2}^\circ$ for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be

installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34608, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the

pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative above-ground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in § 192.123.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 63 FR 53900, Sept. 15, 2003; Amdt. 192-94, 69 FR 32895, June 14, 2004]

§ 192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the

casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
Inches (Millimeters)		
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a trans-

mission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in § 192.3, must be installed in accordance with § 192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-98, 69 FR 48406, Aug. 10, 2004]

§ 192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable oper-

ating pressure calculated under § 192.620, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this construction issue:	The pipeline segment must meet this additional construction requirement:
(a) Quality assurance	(1) The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. (2) The quality assurance plan for applying and testing field applied coating to girth welds must be: (i) Equivalent to that required under § 192.112(f)(3) for pipe; and (ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with § 192.243(b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in § 192.327, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage. (2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

[72 FR 62176, Oct. 17, 2008]

Subpart H—Customer Meters, Service Regulators, and Service Lines

§ 192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.355 Customer meters and regulators: Protection from damage.

(a) *Protection from vacuum or back pressure.* If the customer's equipment might create either a vacuum or a back

pressure, a device must be installed to protect the system.

(b) *Service regulator vents and relief vents.* Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—

- (1) Be rain and insect resistant;
- (2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and
- (3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) *Pits and vaults.* Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.357 Customer meters and regulators: Installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

§ 192.359 Customer meter installations: Operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.361 Service lines: Installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:

- (1) In the case of a metal service line, be protected against corrosion;
- (2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and
- (3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

- (1) It must be encased in a gas tight conduit;
- (2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and
- (3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend

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above grade, terminating in a rain and insect resistant fitting.

(g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with § 192.321(e).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996; Amdt. 192-85, 63 FR 37503, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service lines: Location of valves.

(a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service lines: General requirements for connections to main piping.

(a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is in-

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stalled to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) *Compression-type connection to main.* Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.

(b) If a threaded tap is being inserted, the requirements of § 192.151 (b) and (c) must also be met.

§ 192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37503, July 13, 1998]

§ 192.375 Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that—

(1) It may be installed in accordance with § 192.321(g); and

(2) It may terminate above ground level and outside the building, if—

(1) The above ground level part of the plastic service line is protected against deterioration and external damage; and

(i) The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building must be protected against external damage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.377 Service lines: Copper.

Each copper service line installed within a building must be protected against external damage.

§ 192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

§ 192.381 Service lines: Excess flow valve performance standards.

(a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

(1) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(i) Upon closure, reduce gas flow—

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

[Amdt. 192-79, 61 FR 31459, June 20, 1996, as amended by Amdt. 192-80, 62 FR 2619, Jan. 17, 1997; Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-121, 81 FR 71001, Oct. 14, 2016]

§ 192.383 Excess flow valve installation.

(a) *Definitions.* As used in this section:

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Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence (SFR).

(b) *Installation required.* An EFV installation must comply with the performance standards in §192.381. After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

- (1) A single service line to one SFR;
- (2) A branched service line to a SFR installed concurrently with the primary SFR service line (*i.e.*, a single EFV may be installed to protect both service lines);
- (3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;
- (4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and
- (5) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

(c) *Exceptions to excess flow valve installation requirement.* An operator need not install an excess flow valve if one or more of the following conditions are present:

- (1) The service line does not operate at a pressure of 10 psig or greater throughout the year;
- (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer;
- (3) An EFV could interfere with necessary operation or maintenance ac-

tivities, such as blowing liquids from the line; or

(4) An EFV meeting the performance standards in §192.381 is not commercially available to the operator.

(d) *Customer's right to request an EFV.* Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

(e) *Operator notification of customers concerning EFV installation.* Operators must notify customers of their right to request an EFV in the following manner:

(1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.

(2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.

(3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.

(4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date.

(5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a

general notification in a prominent location frequented by customers.

(f) *Operator evidence of customer notification.* An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.

(g) *Reporting.* Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by §191.11.

[Amdt. 192-121, 81 FR 71001, Oct. 14, 2016; 81 FR 72739, Oct. 21, 2016]

§ 192.385 Manual service line shut-off valve installation.

(a) *Definitions.* As used in this section:

Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

(b) *Installation requirement.* The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.

(c) *Accessibility and maintenance.* Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

[Amdt. 192-121, 81 FR 71002, Oct. 14, 2016]

Subpart I—Requirements for Corrosion Control

SOURCE: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

§ 192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977, as amended by Amdt. 192-102, 71 FR 13303, Mar. 15, 2006]

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§ 192.453 General.

The corrosion control procedures required by § 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994]

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of § 192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977; Amdt. 192-39, 47 FR 9844, Mar. 8, 1982; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003]

§ 192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§ 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 192-87, 64 FR 56981, Oct. 22, 1999]

§ 192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type

must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§ 192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§ 192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately

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protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by §§ 192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-35A, 45 FR 23441, Apr. 7, 1980; Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-93, 68 FR 53900, Sept. 15, 2003; Amdt. 192-114, 75 FR 48603, Aug. 11, 2010]

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§ 192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m³) at standard conditions (4 parts per million) may

not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-

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built drawings or other construction records.

[72 FR 20059, Apr. 23, 2007]

§ 192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

- (1) Only be a light surface oxide; or
- (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§ 192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by § 192.479.

[Amdt. 192-93, 68 FR 53901, Sept. 15, 2003]

§ 192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial measures: Transmission lines.

(a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating

pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996; Amdt. 192-88, 64 FR 69664, Dec. 14, 1999; Amdt. 192-119, 80 FR 181, Jan. 5, 2015]

§ 192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-88, 64 FR 69665, Dec. 14, 1999]

§ 192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) *General graphitization.* Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or

any leakage might result, must be replaced.

(b) *Localized graphitization.* Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§ 192.490 Direct assessment.

Each operator that uses direct assessment as defined in §192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard ¹
External corrosion	§ 192.925 ²
Internal corrosion in pipelines that transport dry gas.	§ 192.927
Stress corrosion cracking	§ 192.929

¹ For lines not subject to subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§ 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

² In § 192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

[Amdt. 192-101, 70 FR 61575, Oct. 25, 2005]

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or

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that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amdt. 192-78, 61 FR 28785, June 6, 1996]

Subpart J—Test Requirements

§ 192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and §192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

(e) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §192.143.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-60, 53 FR 36029, Sept. 16, 1988; Amdt. 192-60A, 54 FR 5485, Feb. 3, 1989; Amdt. 192-120, 80 FR 12779, Mar. 11, 2015]

§ 192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the

pressure at or above the test pressure for at least 8 hours.

(d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-85, 63 FR 37504, July 13, 1998; Amdt. 192-94, 69 FR 32895, June 14, 2004; Amdt. 195-94, 69 FR 54592, Sept. 9, 2004; Amdt. 192-120, 80 FR 12779, Mar. 11, 2015]

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially haz-

ardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507 of this subpart.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-74, 61 FR 18517, Apr. 26, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be

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more than three times the pressure determined under § 192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-77, 61 FR 27793, June 3, 1996; 61 FR 45905, Aug. 30, 1996; Amdt. 192-85, 63 FR 37504, July 13, 1998]

§ 192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records.

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

- (1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
- (2) Test medium used.
- (3) Test pressure.
- (4) Test duration.
- (5) Pressure recording charts, or other record of pressure readings.
- (6) Elevation variations, whenever significant for the particular test.
- (7) Leaks and failures noted and their disposition.

(b) Each operator must maintain a record of each test required by

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§§ 192.509, 192.511, and 192.513 for at least 5 years.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-93, 68 FR 63901, Sept. 15, 2003]

Subpart K—Uprating

§ 192.551 Scope.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General requirements.

(a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) *Records.* Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) *Written plan.* Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under §§ 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under